



One Firm Worldwide<sup>SM</sup>



## WHITE PAPER

June 2016

### A Guide to PHMSA's Proposed Rule Expanding Natural Gas Pipeline Safety Requirements

In response to a 2010 pipeline safety incident in San Bruno, California, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration has issued a proposed rule to significantly expand safety requirements applicable to natural gas pipelines. The agency's wide-ranging proposal would, among other requirements, impose more robust integrity management requirements to pipeline segments located within high consequence areas, impose a subset of these integrity management requirements to segments located within moderate consequence areas (creating a new middle tier of pipelines), and establish a new process for verifying a pipeline's maximum allowable operating pressure. The proposed rule would require natural gas pipeline operators to make and retain records documenting compliance with hundreds of regulatory requirements. Comments on the proposed rule are due July 7, 2016. This White Paper provides a detailed guide to the proposed rule and highlights four "take-aways" for executives and in-house counsel.

## TABLE OF CONTENTS

Four Take-Aways From PHMSA's Proposed Rule .....	1
A Guide to the Proposed Rule .....	2
A Three-Tiered Approach to Gas Pipeline Safety.....	3
Definition of "Moderate Consequence Areas".....	4
Integrity Management Requirements for Pipeline Segments in Moderate Consequence Areas .....	4
Implications of Establishing a Middle "Moderate" Tier of Pipeline Safety Requirements.....	5
MAOP Verification and Treatment of "Grandfathered" Pipeline Facilities.....	6
Scope and Deadlines for PHMSA's Proposed MAOP Verification Requirement .....	6
Methods for Determining MAOP .....	7
Fracture Mechanics Modeling for Failure Stress and Crack Growth Analysis .....	8
Implications of PHMSA's Approach to MAOP Verification.....	9
Strengthening the Integrity Management Requirements Within High Consequence Areas .....	10
Collecting, Validating, and Integrating Pipeline Data.....	10
Risk Assessment .....	12
Actions to Address Particular Threats.....	12
New Assessment Methods.....	13
New Requirements for Selecting and Using Assessment Methods.....	14
New Preventive and Mitigative Measures.....	15
New Requirements Applicable to All Pipelines, Not Just Pipelines Located in HCAs and MCAs.....	16
Repair Criteria.....	16
Inspection of Pipelines Following Severe Events.....	17
Reporting MAOP Exceedances.....	17
Management of Change Procedures .....	17
Corrosion Control .....	18
Expanding the Regulation of Gas Gathering Lines .....	19
Topics Deferred to the Future.....	21
Lawyer Contacts.....	22

The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration's ("PHMSA") recent notice of proposed rulemaking would significantly expand the safety requirements that apply to the nation's natural gas pipelines.<sup>1</sup> Comments on the NPRM are due July 7, 2016. This White Paper provides a detailed guide to PHMSA's proposed rule and highlights four "take-aways" from the NPRM for executives and in-house counsel.

## FOUR TAKE-AWAYS FROM PHMSA'S PROPOSED RULE

- 1. We all have work to do.** PHMSA has proposed major changes to its gas pipeline safety rules. Some of the proposed changes impose new duties that will take decades to fulfill, such as the duty to conduct assessments on a new category of pipeline segments—those located in Moderate Consequence Areas ("MCAs"). Other proposed duties will require immediate action by pipeline operators, such as the duty to immediately repair a pipeline when certain conditions are present. Some new duties are expressed by adding multiple pages of regulatory text, such as new Appendix F, which will govern the use of Guided Wave Ultrasonic Testing. Other new duties are expressed with deceptive brevity, such as PHMSA's proposal to require compliance with nine additional industry standards or reports by incorporating them by reference into the proposed rule. Stakeholders will need to dedicate significant time and effort to comply with the final rule that emerges from PHMSA's proposal.
- 2. It is time to further integrate Integrity Management into other gas pipeline safety efforts.** Under PHMSA's current gas pipeline safety rules, the Integrity Management rules set out in Subpart O of Part 192 could be viewed as a distinct program within the overall pipeline safety program. Currently, the requirements of Subpart O are defined primarily within Subpart O itself. PHMSA proposes to amend Subpart O to add more than 25 new references to requirements defined outside of Subpart O. Some of these requirements would be substantial, such as Section 192.506's new requirements applicable to "spike" hydrostatic pressure tests and Section 192.624's new requirements related to
- 3. It is time to check in with your lawyers.** The federal gas pipeline safety rules are based on, and refer liberally to, industry standards developed by engineers. For pipeline operators, employees with technical backgrounds are the essential resource for addressing pipeline safety compliance matters. Likewise, technical knowledge is critical to PHMSA's audit function. But there is an important role for lawyers as well. Pacific Gas & Electric Company ("PG&E") is being criminally prosecuted for its alleged failure to comply with PHMSA's pipeline safety regulations in connection with the San Bruno incident. The role of lawyers will grow in importance in response to PHMSA's proposed rule. In addition to imposing new substantive duties, PHMSA plans to transform the way operators must document compliance. As proposed, Section 192.13(e) states that: (i) each operator "must make and retain records that demonstrate compliance" with Part 192, keeping these records for the retention periods specified in Appendix A to Part 192; and (ii) these records "must be reliable, traceable, verifiable, and complete." Proposed Appendix A to Part 192 lists 85 separate record retention requirements. In light of the PHMSA's proposed rule and the criminal charges brought against PG&E, pipeline operators need to reevaluate how they document compliance with Part 192.
- 4. There is no time like the present.** Whether preparing comments on PHMSA's proposed rule or taking steps to comply with the final rule that emerges from PHMSA's proposal, an intense focus on pipeline safety will have clear benefits for the owners and operators of natural gas pipelines. In addition

---

<sup>1</sup> Notice of Proposed Rule, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Docket No. PHMSA-2011-0023, 81 Fed. Reg. 20,722, 20,732 (April 8, 2016) ("proposed rule" or "NPRM"). See also 81 Fed. Reg. 29,830 (May 13, 2016) (extending comment due date to July 7, 2016).

to the proposed rules, the NPRM identifies known regulatory gaps that PHMSA intends to address through future rulemakings. Moreover, future safety incidents may spur congressional or regulatory responses on an industry-wide basis and may give rise to civil or criminal claims against individual pipeline operators. It is difficult to imagine that pipeline safety matters will become less critical in the future.

## A GUIDE TO THE PROPOSED RULE

PHMSA's proposed rule constitutes the primary federal regulatory response to a natural gas pipeline safety incident that occurred in San Bruno, California, on September 9, 2010. Following the San Bruno incident, PHMSA issued an Advanced Notice of Proposed Rulemaking addressing potential changes to its gas pipeline safety rules, the National Transportation Safety Board ("NTSB") issued a report on the incident, and Congress passed the 2011 Pipeline Safety Act.<sup>2</sup> These responses to the San Bruno incident included a wide range of proposals, recommendations, and mandates intended to improve the safety of natural gas pipelines. In addition, the Department of Justice ("DOJ") filed criminal charges against PG&E, the owner and operator of the gas pipeline in question, alleging violations of PHMSA's pipeline safety rules.<sup>3</sup>

As reflected in PHMSA's proposed rule, the San Bruno incident has raised important questions about the agency's Integrity Management rules.<sup>4</sup> Currently, PHMSA's pipeline safety rules are divided into two tiers—one set of rules applies to all gas transmission pipelines, while heightened Integrity Management requirements apply to pipeline segments located within HCAs.

These Integrity Management rules require pipeline operators to: (i) identify each segment of a natural gas transmission pipeline located in an HCA (i.e., an area where a leak or rupture could do the most harm); (ii) develop and implement a "baseline" safety assessment plan that identifies the potential threats to each of these "covered segments"; (iii) prioritize covered segments for assessment; (iv) evaluate preventive and mitigative measures; (v) remediate conditions; and (vi) implement a process for continual evaluation and assessment of the integrity of the covered segment.<sup>5</sup>

The San Bruno incident also raised questions about how pipeline operators establish and verify the maximum allowable operating pressure, or "MAOP," of pipeline segments, particularly where a pipeline's MAOP was established using the "grandfather" clause. MAOP is an essential element of PHMSA's pipeline safety rules because it defines the highest pressure at which a pipeline can safely operate. The "grandfather" clause allowed pipeline operators to define a pipeline segment's MAOP as the highest actual operating pressure at which the pipeline operated during the five years preceding July 1, 1970.<sup>6</sup> In contrast, for pipeline segments built after this date, MAOP had to be established based on the results of a post-construction hydrostatic pressure test and the design pressure of the weakest element of the pipeline segment.<sup>7</sup>

This *White Paper* discusses the following aspects of PHMSA's proposal:

1. The shift to a three-tiered approach to safety by applying a subset of the Integrity Management requirements to newly defined "Moderate" Consequence Areas.

---

2 Advanced Notice of Proposed Rulemaking, Pipeline Safety: Safety of Gas Transmission Pipelines, Docket No. PHMSA-2011-0023, 81 Fed. Reg. 53,086 (Aug. 25, 2011) ("ANPRM"); National Transportation Safety Board, *Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010*, Pipeline Accident Report NTSB/PAR-11/01 (Aug. 30, 2011) (the "NTSB San Bruno Report"); and Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub. L. 112-90, 125 Stat. 1904 (2012) ("2011 Pipeline Safety Act").

3 Superseding Indictment, *U.S. v. Pacific Gas and Electric Co.*, No. 3:14-cr-00175 (N.D. Cal. July 30, 2014), ECF No. 22 (the "San Bruno Indictment").

4 See 49 C.F.R. Part 192, Subpart O. These rules went into effect in 2004. Pipeline Safety: Pipeline Integrity Management in High Consequence Areas, Final Rule, Docket No. RPSA-00-7666, 68 Fed. Reg. 69,788 (Dec. 15, 2003).

5 49 C.F.R. § 192.911.

6 49 C.F.R. § 192.619(c). The "grandfather" clause was available only when the pipeline segment was "found to be in satisfactory condition, considering its operating and maintenance history[.]" 49 C.F.R. § 192.619(c).

7 Specifically, for pipeline segments installed after July 1, 1970, the MAOP of a pipeline segment equaled the lowest of the following: (i) a calculation based on the design pressure of the weakest element in the segment; (ii) a calculation based on the results of the segment's post-construction pressure test; (iii) the highest actual operating pressure at which the pipeline operated during the five years preceding November 12, 1970; or (iv) the pressure determined by the operator to be "the maximum safe pressure after considering the history of the segment[.]" 49 C.F.R. § 192.619(a).

2. The verification of MAOP, including the treatment of “grandfathered” pipeline facilities, as well as PHMSA’s new focus on records retention and verification.
3. The strengthening of Integrity Management requirements within HCAs.
4. New requirements applicable to all gas pipelines, not just pipelines located in HCAs and MCAs.
5. The expansion of requirements applicable to natural gas gathering lines.
6. PHMSA’s decision to postpone consideration of other potential additions to the gas pipeline safety rules.

### A THREE-TIERED APPROACH TO GAS PIPELINE SAFETY

PHMSA’s proposed rule distinguishes between three tiers of gas transmission pipelines: (i) those located in HCAs; (ii) those located in MCAs; and (iii) those located outside of HCAs and MCAs. Pipeline segments located in MCAs constitute a middle tier of segments that will be subject to some, but not all, of the requirements that apply to HCAs. The creation of this new tier of pipeline segments reflects PHMSA’s policy decision “to apply progressively more protection for progressively greater consequence locations.”<sup>8</sup> In developing this “middle” tier, PHMSA decided not to simply expand the definition of HCAs such that the full Integrity Management program would apply to more miles of pipeline, which would run counter to a “graded approach” based on risk.<sup>9</sup> PHMSA states that its proposal “balances the need to provide additional protections for persons within the potential impact radius” of a pipeline rupture, even though located outside of a defined HCA, “and the

need to prudently apply IM resources in a fashion that continues to emphasize the risk priority of HCAs.”<sup>10</sup>

In proposing the use of MCAs, PHMSA rejected an alternative “tiered” approach, which would have applied less stringent Integrity Management rules to pipelines that operate at less than 30 percent of the line’s specified minimum yield strength (“SMYS”).<sup>11</sup> Rather than use the 30 percent SMYS threshold to define the contours of the entire Integrity Management program, PHMSA’s proposal continues to differentiate pipeline segments using the 30 percent SMYS threshold only with respect to specific requirements.<sup>12</sup>

PHMSA also decided that the creation of MCAs did not eliminate the need for continued reliance on “class” locations. A “class location unit” is an onshore area that extends 220 yards on either side of the centerline of any continuous one-mile length of pipeline as follows: (i) a Class 1 location unit has 10 or fewer buildings intended for human occupancy; (ii) a Class 2 location unit has more than 10 but fewer than 46 buildings intended for human occupancy; (iii) a Class 3 location unit has 46 or more buildings intended for human occupancy or a building or other occupied area within 100 yards of a pipeline occupied by 20 or more persons above a minimum amount of time; and (iv) a Class 4 location unit is one where buildings with four or more stories above ground are prevalent.<sup>13</sup> For various elements of PHMSA’s regulations, more extensive safety requirements apply as the “class” location increases. PHMSA proposes to retain distinctions between class location because the concept “is integral to determining MAOPs, design pressures, pipeline repairs, [HCAs], and operating and maintenance inspections and surveillance intervals.”<sup>14</sup>

---

8 NPRM, 81 Fed. Reg. at 20,732.

9 NPRM, 81 Fed. Reg. at 20,732.

10 NPRM, 81 Fed. Reg. at 20,743.

11 NPRM, 81 Fed. Reg. at 20,743.

12 See, e.g., Proposed § 192.506(a), 81 Fed. Reg. at 20,830 (requiring a “spike” pressure test if certain integrity management threats are present on a line that is operated at 30% or more of SMYS); Proposed § 192.710(c)(8), 81 Fed. Reg. at 20,838 (for new integrity assessment requirements outside of HCAs, establishing separate inspection requirements applicable to a segment with an MAOP less than 30% of SMYS (a “low stress segment”) for purposes of assessing the threats of external corrosion and internal corrosion); and 49 C.F.R. § 192.939 (2015) (authorizing different integrity management reassessment intervals for segments, depending on the percentage of SMYS at which the segment operates).

13 49 C.F.R. § 192.5.

14 NPRM, 81 Fed. Reg. at 20,743.

Because a class location unit is an area along “any contiguous 1-mile” length of a pipeline, a cluster of 46 or more buildings near one point on a pipeline can result in two miles of pipeline being classified as a Class 3 location. In contrast, an operator has the option of defining an HCA with more precision. An operator is permitted to define an HCA as the area within a “potential impact circle” containing: (i) 20 or more buildings intended for human occupancy (with some exceptions); or (ii) an “identified site.”<sup>15</sup> The purpose of a “potential impact circle” is to define the area around each potential point of failure along a pipeline that could be affected if the pipeline ruptures. Thus, the potential impact circle relies on a “potential impact radius,” which is measured using a formula that takes into account the maximum allowable operating pressure and the nominal diameter of the pipeline segment.<sup>16</sup> Alternatively, an operator has the option to define HCAs in a way that includes all pipelines within a Class 3 or 4 location.<sup>17</sup>

Conceptually, an “identified site” is an alternative way to identify areas where people are likely to be present, and thus affected by a pipeline rupture. An identified site means: (i) an outside area or open structure that is occupied by 20 or more persons on at least 50 days in any 12-month period, such as a beach, playground, or camping ground; (ii) a building that is occupied by 20 or more persons on at least five days a week for 10 weeks in any 12-month period, such as religious facilities, office buildings, community centers, or general stores; or (iii) a facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate, such as a hospital, prison, school, or retirement facility.<sup>18</sup> Thus, whereas a “class location” is a broad designation that corresponds only roughly to a location where a rupture could do serious harm, operators

have the option to define an HCA more precisely to identify a pipeline segment whose rupture could do the most harm.

#### Definition of “Moderate Consequence Areas”

PHMSA proposes to define an MCA using a modified version of the criteria used to define an HCA. A point along a pipeline segment is within an MCA if the “potential impact circle” around that point contains: (i) five or more buildings intended for human occupancy (with some exceptions) (as compared to 20 or more such buildings when defining an HCA); (ii) an “occupied site”; or (iii) “a right-of-way for a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway” as defined by the Federal Highway Administration.<sup>19</sup> An “occupied site” includes: (i) an outside area or open structure that is occupied by five or more persons on at least 50 days in any 12-month period, such as a beach, playground, or camping ground (as compared to 20 or more persons when defining an HCA); or (ii) a building that is occupied by five or more persons on at least five days a week for 10 weeks in any 12-month period, such as religious facilities, office buildings, community centers, or general stores (as compared to 20 or more persons when defining an HCA).<sup>20</sup> Any area within an MCA that meets the more selective HCA criteria remains a “covered segment” subject to PHMSA’s Integrity Management rules.

#### Integrity Management Requirements for Pipeline Segments in Moderate Consequence Areas

PHMSA proposes to add Section 192.710, which would require integrity assessments of onshore transmission pipelines located outside of an HCA but within a Class 3 or a Class 4 location or an MCA (but only if the segment can accommodate inspection by means of an instrumented in-line inspection tool,

---

15 49 C.F.R. § 192.903.

16 49 C.F.R. § 192.903.

17 49 C.F.R. § 192.903. Under this second method, an operator can define an HCA as: (i) a Class 3 or 4 location; (ii) any area in a Class 1 or 2 location where the pipeline segment’s “potential impact radius” is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or (iii) any area in a Class 1 or 2 location where the pipeline segment’s “potential impact circle” contains an identified site. *Id.*

18 49 C.F.R. § 192.903.

19 Proposed § 192.3, 81 Fed. Reg. at 20,826.

20 Proposed § 192.3, 81 Fed. Reg. at 20,826.

i.e., a “smart pig”).<sup>21</sup> A “smart pig” is a “device placed inside the pipeline to measure the thickness of the pipeline walls” and that “ultrasonically or electromagnetically detects defects in a pipe.”<sup>22</sup> For a pipeline segment subject to new Section 192.710, the operator must perform the initial assessments within 15 years of the rule’s effective date and must perform periodic reassessments every 20 years thereafter.<sup>23</sup>

To perform an assessment, an operator must select one of the following methods: an internal inspection tool, a Subpart J pressure test, a “spike” hydrostatic pressure test, Guided Wave Ultrasonic Testing (“GWUT”), direct assessment,<sup>24</sup> or another “technology or technologies” that an operator “demonstrates can provide an equivalent understanding of the line pipe for each of the threats to which the pipeline is susceptible.”<sup>25</sup> With a few adjustments, these are the same assessment methods applicable to covered segments within HCAs under PHMSA’s Integrity Management rules, as those rules would be revised by the NPRM. As is true under the Integrity Management rules, under Section 192.710, an operator must select an assessment method “capable of identifying anomalies and defects associated with each of the threats to which the pipeline is susceptible[.]”<sup>26</sup> In lieu of a new assessment, an operator is permitted to rely on a prior assessment if the assessment meets the requirements for in-line inspection defined in the Integrity Management rules.<sup>27</sup>

As discussed below, the proposed rule also requires pipelines operators to verify the MAOP of pipeline segments within MCAs in certain circumstances.

## Implications of Establishing a Middle “Moderate” Tier of Pipeline Safety Requirements

Several aspects of the new Section 192.710 are intended to partially mitigate the burdens of the new requirement. First, the new integrity assessments would be required for a segment in an MCA only if the segment can accommodate inspection by means of a smart pig. Second, the schedule for assessing pipeline segments within MCAs would be longer than the schedule for assessing “covered segments” within HCAs. Third, there is a separate set of inspection requirements applicable to a segment with an MAOP less than 30 percent of SMYS (a “low stress segment”) for purposes of assessing the threats of external corrosion and internal corrosion.<sup>28</sup>

PHMSA states that its proposal for MCAs is comparable to the 2012 voluntary commitment made by members of the Interstate Natural Gas Association of America (“INGAA”), and that this similarity “shows a common understanding of the importance of this issue and a path towards a solution.”<sup>29</sup> INGAA’s commitment would extend the application of Integrity Management principles in four stages, which would result, by 2030, in applying Integrity Management principles to 100 percent of INGAA pipeline mileage along which people live, work, or congregate (which is 80 percent of INGAA’s total pipeline mileage).<sup>30</sup> After 2030, Integrity Management principles would be extended to the 20 percent of pipeline mileage where no population resides. It appears that PHMSA’s new MCA requirements are being imposed in addition to INGAA’s voluntary commitments rather than as a replacement for those commitments.<sup>31</sup>

---

21 Proposed § 192.710, 81 Fed. Reg. at 20,838-39.

22 8-S Williams & Meyers, *Oil and Gas Law* (LexisNexis Matthew Bender 2015) (citing *Township of Piscataway v. Duke Energy*, 488 F.3d 203, 211 (3rd Cir. 2007) and General Accounting Office, *Trans-Alaska Pipeline* 100 (GAO/RCED-91-89, July 19, 1991).

23 Proposed § 192.710(b)(1), 81 Fed. Reg. at 20,838.

24 Proposed § 192.71(c)(6), 81 Fed. Reg. at 20,838.

25 Proposed § 192.710(c)(7), 81 Fed. Reg. at 20,838.

26 Proposed § 192.710(c), 81 Fed. Reg. at 20,838.

27 Proposed § 192.710(b)(2), 81 Fed. Reg. at 20,838 (referencing in-line inspection requirements in proposed § 192.921(a)(1)).

28 Proposed § 192.710(c)(8), 81 Fed. Reg. at 20,838. The NPRM’s requirements for pipelines operating at stress levels of less than 30% of SMYS are based on technical information provided in the Interstate Natural Gas Association of America/American Gas Association Final Report No. 13–180, *Leak vs. Rupture Thresholds for Material and Construction Anomalies*, December 2013. NPRM, 81 Fed. Reg. at 20,813.

29 NPRM, 81 Fed. Reg. at 20,731.

30 NPRM, 81 Fed. Reg. at 20,730.

31 See, e.g., NPRM, 81 Fed. Reg. at 20,731 (“Given INGAA’s commitment, feedback from the ANPRM, the results of incident investigations, and IM considerations, PHMSA has determined it is appropriate to improve aspects of the current IM program”).

## MAOP VERIFICATION AND TREATMENT OF “GRANDFATHERED” PIPELINE FACILITIES

The San Bruno incident occurred on a pipeline segment installed before 1970 with an MAOP that had been established pursuant to the so-called “grandfather” clause.<sup>32</sup> The NTSB’s report on the San Bruno incident concluded that, “if the grandfathering of older pipelines had not been permitted,” then the line in question “would have undergone a hydrostatic pressure test that would likely have exposed the defective pipe that led to this accident.”<sup>33</sup> Relying on PHMSA statistics, the NTSB report stated that approximately 61 percent of onshore gas transmission pipelines (about 180,000 miles) were installed prior to 1970, and therefore operators had the option to establish the MAOP on these lines using the grandfather clause.<sup>34</sup> The NTSB recommended that PHMSA eliminate the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a “spike” test.<sup>35</sup>

The 2011 Pipeline Safety Act directed the Department of Transportation to: (i) require each operator of gas transmission lines with insufficient records to “reconfirm” the MAOP for the line “as expeditiously as economically feasible,” and (ii) “determine what actions are appropriate for the pipeline owner or operator to take to maintain safety until” the MAOP is confirmed.<sup>36</sup> In two Advisory Bulletins, PHMSA advised pipeline operators that the Integrity Management rules recognize that “each pipeline is unique and has its own specific risk profile” that depends on

the specific facts related to that pipeline, and that one of the “fundamental tenets of the IM program is that pipeline operators must be aware of the physical attributes of their pipeline as well as the physical environment that it transverses.”<sup>37</sup> If the required information “is unknown, or unknowable, a more conservative approach to operation is dictated.” Moreover, with respect to data relied on to establish a pipeline segment’s MAOP, the operator must ensure that the records used are “reliable, traceable, verifiable, and complete.”<sup>38</sup> In 2012, PHMSA revised one of its annual reporting forms to require operators to identify the total amount of pipeline mileage for which the operator’s MAOP data was incomplete, broken down by class location and by whether the line was within an HCA.<sup>39</sup>

### Scope and Deadlines for PHMSA’s Proposed MAOP Verification Requirement

To address MAOP verification, PHMSA proposes a new regulation, Section 192.624, which would apply to onshore steel transmission pipelines if two conditions are met. First, the pipeline segment must be located in: (i) an HCA; (ii) a Class 3 or Class 4 location; or (iii) an MCA (if the MCA segment can accommodate inspection by an in-line “smart pig”).<sup>40</sup> Second, the pipeline segment must: (i) have experienced a “reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test,” as the result of certain types of defects listed in the regulation;<sup>41</sup> (ii) lack “reliable, traceable, verifiable, and complete” records of a Subpart J pressure test; or (iii) have an MAOP established using Section 192.619(c)’s “grandfather” clause.<sup>42</sup>

---

32 49 C.F.R. § 192.619(a)(3).

33 NTSB San Bruno Report at 106-07.

34 NTSB San Bruno Report at 35.

35 NTSB San Bruno Report at 35; NTSB Recommendation P-11-14, at 129.

36 2011 Pipeline Safety Act, § 23, 125 Stat. at 1918, codified at 49 U.S.C. § 60139.

37 PHMSA Advisory Bulletin 11-01, “Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation,” Docket No. PHMSA-2010-0381, 76 Fed. Reg. 1504 (Jan. 10 2011).

38 PHMSA Advisory Bulletin 12-06, “Pipeline Safety: Verification of Records,” Docket No. PHMSA-2012-0068, 77 Fed. Reg. 26,822 (May 7, 2012).

39 See Form PHMSA F 7100.2-1. See Notice and Request for Comments, Docket No. PHMSA-2012-0024, 77 Fed. Reg. 58,616, 58,618-20 (Sept. 21, 2012) (discussing the addition of Parts Q and R to the Form PHMSA F 7100.2-1, and explaining that these changes were made to comply with Section 23 of the 2011 Pipeline Safety Act).

40 Proposed §192.624(a), 81 Fed. Reg. at 20,833-34.

41 Proposed §192.624(a)(1), 81 Fed. Reg. at 20,834. The regulation lists incidents due to “an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking[.]”

42 Proposed §192.624(a), 81 Fed. Reg. at 20,833-34.



An operator must comply with the MAOP verification requirement according to the following schedule, which counts from the effective date of new Section 192.624: (i) within one year, “develop and document a plan for completion of all actions” required by new Section 192.624; (ii) within eight years, complete all required actions on at least 50 percent of the mileage of the locations covered by the new rule; and (iii) within 15 years, complete the required actions on the remaining mileage of those locations.<sup>43</sup>

### Methods for Determining MAOP

For a pipeline segment subject to new Section 192.624, an operator must establish MAOP using one of the following methods: (i) pressure test; (ii) pressure reduction; (iii) Engineering Critical Assessment (“ECA”); (iv) pipe replacement; (v) pressure reduction for a segment with a small potential impact radius; or (vi) alternative technology.<sup>44</sup> Each of these MAOP verification methods is subject to specific requirements and limitations set out in proposed Section 192.624(c). Two of these methods, pressure tests and Engineering Critical Assessments, are discussed in more detail here.

A pressure test (sometimes referred to as a “hydrostatic” pressure test) requires filling a pipeline with a test medium, pressurizing the segment up to a target (or test) pressure level, and maintaining the pressure at or above the test level for at least eight hours.<sup>45</sup> Under the proposed rule, to establish MAOP, the test pressure must be equal to at least the segment’s MAOP divided by 1.25 (or divided by 1.50 if the segment is located in a Class 3 or 4 location).<sup>46</sup> A Section 192.506 “spike” pressure test must be conducted if the pipeline segment: (i) “includes

legacy pipe or was constructed using legacy construction techniques,” or (ii) the pipeline “has experienced an incident, as defined by § 191.3, since its most recent successful subpart J pressure test,” due to a list of defects with problematic causes.<sup>47</sup> Like an ordinary pressure test, a “spike” pressure test maintains a specified pressure level (referred to as the “baseline” test pressure) for at least eight hours. After the baseline test pressure stabilizes, and within the first two hours of the eight-hour test interval, the test pressure “must be raised (spiked) to a minimum of the lesser of 1.50 times MAOP or 105 percent SMYS,” and this spiked pressure level must be maintained for at least 30 minutes.<sup>48</sup>

The current pipeline safety regulations do not allow operators to use an Engineering Critical Assessment when establishing or assessing a pipeline segment’s integrity. The proposed rule allows this method, which is an “analytical procedure, based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections.”<sup>49</sup> The ECA must: (i) “assess threats, loading, and operational conditions relevant to those threats, such as rights-of-way, mechanical and fracture properties, in-service degradation or failure processes, and initial and final defect size relevance”; and (ii) “quantify the coupled effects of any defect in the pipeline.”<sup>50</sup>

The ECA also must: (i) “integrate and analyze” the results of any documentation of the pipeline segment’s constituent material, if

---

43 Proposed § 192.624(b), 81 Fed. Reg. at 20,834. Upon “submittal of a notification” to the Associate Administrator of the Office of Pipeline Safety, an operator may request an extension of these two deadlines by up to one year if the delay is the result of “operational” or “environmental” constraints.

44 Proposed § 192.624(c), 81 Fed. Reg. at 20,834-36. An operator can use the alternative technology method only if it provides PHMSA at least 180 days advance notice and obtains a “no objection letter” from PHMSA’s Associate Administrator of Pipeline Safety. As part of this notice, the operator must submit an “alternative technical evaluation,” the requirements of which are described in the proposed regulation. Proposed § 192.624(c)(6), 81 Fed. Reg. at 20,836-37. The regulation imposes additional requirements that the operator must satisfy when submitting an alternate technology notice to PHMSA. Proposed § 192.624(c)(6)(i)-(xi), 81 Fed. Reg. at 20,837.

45 49 C.F.R. § 192.505.

46 Proposed § 192.624(c)(1)(i), 81 Fed. Reg. at 20,834. See also Proposed § 192.619(a)(2)(ii), 81 Fed. Reg. at 20,833, or 49 C.F.R. § 192.620(a)(2)(ii).

47 Proposed § 192.624(c)(1)(ii), 81 Fed. Reg. at 20,834. The defects listed in Proposed § 192.624(c)(1)(ii) are functionally identical to the defects listed in Proposed § 192.624(a).

48 Proposed § 192.506, 81 Fed. Reg. 20,830-31.

49 Proposed § 192.624(c)(3), 81 Fed. Reg. at 20,835.

50 Proposed § 192.624(c)(3), 81 Fed. Reg. at 20,835.

the segment was subject to Section 192.607's "material verification" requirement, as well as integrate and analyze the results of other tests and assessments listed in the regulation; (ii) analyze any "cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure" using the "techniques and procedures" in three Battelle Final Reports incorporated by reference into the regulation or using "other technically proven methods," and meeting other requirements included in the regulation; (iii) analyze any "metal loss defects not associated with a dent including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe to determine the predicted failure pressure" using a method that meets the requirements included in the regulation, including the use of certain conservative assumptions; and (iv) analyze "interacting defects to conservatively determine the most limiting predicted failure pressure for such defects."<sup>51</sup> The ECA must establish the pipeline segment's MAOP at the lowest predicted failure pressure "for any known or postulated defect, or interacting defects, remaining in the pipe" divided by 1.25 (or by 1.50 if the segment is located in a Class 3 or 4 location).<sup>52</sup>

For line segments that do not have records of a Subpart J pressure test, an operator using the ECA method must develop and implement an in-line inspection program that can detect "wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking."<sup>53</sup> The operator, at "a minimum," must conduct an assessment using a "high resolution magnetic flux leakage" tool, a "high resolution deformation" tool, and either an "electromagnetic acoustic transducer" tool or an "ultrasonic testing" tool.<sup>54</sup> Rather than use these tools, however, an operator may use

"other technology" if: (i) it is "validated by a subject matter expert in metallurgy and fracture mechanics to produce an equivalent understanding of the condition of the pipe"; and (ii) the operator provides PHMSA at least 180 days' advance notice and obtains a "no objection letter" from PHMSA's Associate Administrator of Pipeline Safety.<sup>55</sup> The proposed regulation lists numerous other requirements applicable to the ECA-related in-line inspection program, including the requirement that inspections be performed in accordance with Section 192.493.<sup>56</sup>

### Fracture Mechanics Modeling for Failure Stress and Crack Growth Analysis

Proposed Section 192.624(d) states that, if a pipeline operator "has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects" based on "any ... available information about the pipeline," then the operator "must perform fracture mechanics modeling for failure stress pressure and crack growth analysis to determine the remaining life of the pipeline" at MAOP based on the "applicable test pressures" in accordance with the new rule applicable to "spike" pressure tests.<sup>57</sup> This modeling must take into account "the remaining crack flaw size in the pipeline segment, any pipe failure or leak mechanisms identified during pressure testing, pipe characteristics, material toughness, failure mechanism for the microstructure (ductile and brittle or both), location and type of defect, operating environment, and operating conditions including pressure cycling."<sup>58</sup>

Proposed Section 192.624(d) specifies other criteria governing the performance of fracture mechanics modeling. For example, when the "strength and toughness" of a pipeline's constituent material and the limits on the range of the material's strength and toughness "are unknown," then the analysis "must assume

---

51 Proposed § 192.624(c)(3)(i)(A)–(D), 81 Fed. Reg. at 20,835; [Battelle's Experience with ERW and Flash Welding Seam Failures: Causes and Implications](#) (Task 1.4); Battelle Memorial Institute, "Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams" (Subtask 2.4); Battelle Final Report No. 13–021, "Predicting Times to Failures for ERW Seam Defects that Grow by Pressure Cycle Induced Fatigue (Subtask 2.5)."

52 Proposed § 192.624(c)(3)(i)(E), 81 Fed. Reg. at 20,835.

53 Proposed § 192.624(c)(3)(iii), 81 Fed. Reg. at 20,835–36.

54 Proposed § 192.624(c)(3)(iii), 81 Fed. Reg. at 20,835–36.

55 Proposed § 192.624(c)(3)(iii)(A), 81 Fed. Reg. at 20,836.

56 Proposed § 192.624(c)(3)(iii)(B)–(G), 81 Fed. Reg. at 20,836.

57 Proposed § 192.624(d), 81 Fed. Reg. at 20,837–38 (referencing Proposed § 192.506).

58 Proposed § 192.624(d)(1), 81 Fed. Reg. at 20,837.

material strength and fracture toughness levels corresponding to the type of assessment being performed.”<sup>59</sup> In this situation, for an assessment using a pressure test, the analysis must use “a full size equivalent Charpy upper-shelf energy level of 120 ft-lb and a flow stress equal to the minimum specified ultimate tensile strength of the base pipe material,” while other requirements apply to modeling related to an in-line assessment.<sup>60</sup>

If the fracture mechanics analysis predicts the “remaining life” for a pipeline segment to be five years or less, then, within one year of the analysis, the operator must establish MAOP by performing a pressure test in accordance with Section 192.624(c) (1) or by reducing MAOP in accordance with Section 192.624(c) (2).<sup>61</sup> In addition, the operator must reevaluate the pipeline segment’s “remaining life” no later than before 50 percent of the remaining life has expired, or 15 years. As part of this reevaluation, the operator must “determine and document if further pressure tests or use of other methods are required[.]” If the analysis shows that a 50 percent “remaining life” approach does not “give a sufficient safety factor based upon technical evaluations then a more conservative remaining life safety factor must be used.”<sup>62</sup> Finally, this fracture mechanics analysis “must be reviewed and confirmed by a subject matter expert in both metallurgy and fracture mechanics.”<sup>63</sup>

### Implications of PHMSA’s Approach to MAOP Verification

Hydrostatic pressure testing is the most accurate way to assess certain types of risks at specified MAOP levels, but it is the most expensive way to verify the MAOP of an in-service pipeline segment, in part because the line must be shut down during the test.<sup>64</sup> In-line “smart pig” tools represent a less expensive assessment method, but these tools cannot navigate some pipeline segments because of the segment’s

physical configuration. Under the existing rules, “direct assessment” is the only other preapproved assessment method. But direct examination is capable of evaluating only certain types of risks to a pipeline segment and cannot be used to evaluate other types of risks.

The proposed rule includes measures intended by PHMSA to mitigate the costs associated with MAOP verification. Most notably, the Engineering Critical Assessment method has the potential to evolve into a method that verifies MAOP more cost-effectively than pressure testing. But as the discussion above shows, the ECA method is highly technical, highly complex, requires support from highly qualified subject matter experts, and has never been deployed as contemplated by the proposed rule.

In addition, MAOP verification is required in an MCA pipeline segment only if the segment can accommodate an in-line “smart pig.” In other words, an MCA segment is covered by the MAOP verification rule only if the segment can be evaluated using one of the tools that is less expensive than pressure testing.

The MAOP verification rule also emphasizes records retention. Section 192.624(f) states that each operator “must keep for the life of the pipeline reliable, traceable, verifiable, and complete records of the investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions made in accordance with the requirements of this section.”<sup>65</sup> The phrase “reliable, traceable, verifiable, and complete” does not exist in the current regulations. In the NPRM, PHMSA proposes to include this phrase in eight regulations.<sup>66</sup> As proposed, Section 192.13(e) states that: (i) each operator “must make and retain records that demonstrate compliance” with Part 192, keeping

---

59 Proposed § 192.624(d)(1), 81 Fed. Reg. at 20,837.

60 Proposed § 192.624(d)(1)(i)-(ii), 81 Fed. Reg. at 20,837.

61 Proposed § 192.624(d)(4), 81 Fed. Reg. at 20,838.

62 Proposed § 192.624(d)(5), 81 Fed. Reg. at 20,838.

63 Proposed § 192.624(d)(6), 81 Fed. Reg. at 20,838.

64 See NPRM, 81 Fed. Reg. at 20789-91, 20798-800.

65 Proposed § 192.624(f), 81 Fed. Reg. at 20,838.

66 See Proposed §§ 192.13(e), 192.485(c), 192.607, 192.619(f), 192.624, 192.713, 192.929, and 192.933, 81 Fed. Reg. at 20,828, 20,830, 20,831, 20,833, 20,834, 20,839, 20,845, 20,846. See also Proposed §192.917 (requiring use of objective, traceable, verified, and validated information), 81 Fed. Reg. 20,841.

these records for the retention periods specified in Appendix A to Part 192; and (ii) these records “must be reliable, traceable, verifiable, and complete.”<sup>67</sup> Proposed Appendix A to Part 192 lists 85 separate record retention requirements.<sup>68</sup> Some of the categories of records listed in Appendix A are quite broad. For example, Appendix A identifies as a single record retention requirement the need to retain “records that demonstrate compliance with all of the requirements of subpart O of this part” for the life of the pipeline,<sup>69</sup> despite the fact that the Subpart O Integrity Management rules impose dozens of requirements.

Nonetheless, in the NPRM, PHMSA does not define the phrase “reliable, traceable, verifiable, and complete.” Apparently, PHMSA’s view is that there is no need to define this phrase in its regulations because the agency already has issued two Advisory Bulletins discussing “reliable, traceable, verifiable, and complete” records.<sup>70</sup> But an Advisory Bulletin lacks the legal force of a regulation that has been promulgated using notice and comment rulemaking.<sup>71</sup>

In fact, the first of these two Advisory Bulletins refers to records that are “traceable, verifiable, and complete.”<sup>72</sup> In the second Advisory Bulletin, without explanation, PHMSA adds the term “reliable” to create the phrase “reliable, traceable, verifiable, and complete.”<sup>73</sup> In doing so, PHMSA explains what it means by “traceable” records, “verifiable” records, and by “complete” records, but not what it means by “reliable” records.<sup>74</sup> Moreover, these Advisory Bulletins discuss the concept of “reliable, traceable, verifiable, and complete” records in the context of specific

regulatory requirements. PHMSA now proposes to require operators to retain “reliable, traceable, verifiable, and complete” records with respect to every requirement of Part 192.

## **STRENGTHENING THE INTEGRITY MANAGEMENT REQUIREMENTS WITHIN HIGH CONSEQUENCE AREAS**

In addition to imposing a subset of its Integrity Management rules within MCAs, PHMSA proposes changes to the rules that will apply within HCAs. According to PHMSA, as “specified in the first IM rule, PHMSA expects operators to start with an IM framework, evolve a more detailed and comprehensive IM program, and continually improve their IM programs as they learn more about the IM process and the material condition of their pipelines through integrity assessments.”<sup>75</sup> In the agency’s view, the proposed changes to the Integrity Management rules simply “reflect PHMSA’s expectations regarding the degree of progress operators should be making, or should have made, during the first 10 years of IM program implementation.”<sup>76</sup>

### **Collecting, Validating, and Integrating Pipeline Data**

Under the current Integrity Management rules, Section 192.917(b) imposes a “data gathering and integration” requirement, which is used to identify and evaluate the potential threats to a covered segment. For each covered segment, an operator uses the results of data gathering and integration to perform the other steps in the Integrity Management

---

67 See Proposed §§ 192.13(e), 81 Fed. Reg. at 20,828.

68 Proposed Appendix A to Part 192, 81 Fed. Reg. at 20,848-52.

69 Proposed Appendix A to Part 192, 81 Fed. Reg. at 20,852.

70 See NPRM, 81 Fed. Reg. at 20,734.

71 See, e.g., *Christensen v. Harris County*, 529 U.S. 576, 587 (2000) (stating that guidance documents which explain the agency’s position or interpret the agency’s view of a regulatory requirement deserve “respect . . . but only to the extent that they have power to persuade”) (quoting *Skidmore v. Swift & Co.*, 232 U.S. 134, 140 (1944)).

72 See PHMSA Advisory Bulletin 11-01, 76 Fed. Reg. at 1506.

73 See PHMSA Advisory Bulletin 12-06, 77 Fed. Reg. at 26,822.

74 See PHMSA Advisory Bulletin 12-06, 77 Fed. Reg. at 26,822. The ease with which PHMSA can change the relevant phrase from “traceable, verifiable, and complete” to “reliable, traceable, verifiable, and complete” underscores why an Advisory Bulletin lacks the legal effect of a properly promulgated regulation.

75 NPRM, 81 Fed. Reg. at 20,729.

76 NPRM, 81 Fed. Reg. at 20,729.

process.<sup>77</sup> Currently, Section 192.917(b) states that an operator “must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment,” and must, at a minimum, “gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S,” an industry standard, without specifying this data in the regulation itself.<sup>78</sup> PHMSA’s Subpart O Integrity Management rules are inextricably intertwined with industry standard ASME/ANSI B31.8S (“Managing System Integrity of Gas Pipelines”). The Subpart O regulations restate many of the requirements of “B31.8S,” while incorporating many others by reference.

In the San Bruno Indictment, the DOJ stated that PG&E “knowingly and willfully failed to gather and integrate existing data and information that could be relevant to identifying and evaluating all potential threats” in a specific covered segment.<sup>79</sup> The indictment also stated that “PG&E failed to gather and integrate all relevant data for many of its older transmission lines,” including specific items of information listed in the indictment.<sup>80</sup> In other words, the DOJ has taken the position that a failure to gather and integrate data “that could be relevant” and its failure to gather and integrate “all relevant data” constitutes a criminal violation of Section 192.917(b). DOJ’s claim raises the specter that a pipeline operator could be subject to criminal prosecution if the operator misses a fact that proves relevant in hindsight.

“To provide greater visibility and emphasis on this important aspect of integrity management,” PHMSA proposes to include the requirements of Appendix A to ASME/ANSI B31.8S in the rule itself, rather than simply incorporating them by reference.<sup>81</sup> As revised, Section 192.917(b)(1) would state that, for both covered segments and noncovered segments, an operator must

“integrate information about pipeline attributes and other relevant information, including, but not limited to” 36 expressly referenced types of data. Examples of this “minimum” data include: Section 192.917(b)(1)(i), pipe diameter, wall thickness, grade, seam type and joint factor; Section 192.917(b)(1)(xiii), construction inspection reports, including but not limited to girth weld non-destructive examinations, post-backfill coating surveys, and coating inspection reports; Section 192.917(b)(1)(xx), “leak and failure history including any in-service ruptures or leaks from incident reports, abnormal operations, safety related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences”; Section 192.917(b)(1)(xxxiii), “industry experience for incident, leak and failure history”; and Section 192.917(b)(1)(xxxvi), “other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this Part.”<sup>82</sup>

Operators also must use “objective, traceable, verified, and validated information and data as inputs, to the maximum extent practicable.”<sup>83</sup> If “input is obtained from subject matter experts,” then the operator “must employ measures to adequately correct any bias” in subject matter input. These “bias control measures” may include the training of subject matter experts and the “use of outside technical experts (independent expert reviews) to assess quality of processes and the judgment of” subject matter experts. Operators “must document the names of all” subject matter experts and document the “information submitted by” subject matter experts for the life of the pipeline.<sup>84</sup> The revised rule also defines in more detail the operator’s duty to analyze and integrate data. This includes the duty to analyze the data “for interrelationships

---

77 See, e.g., 49 C.F.R. §§ 192.917(c), 192.935, 192.939.

78 49 C.F.R. § 192.917(b).

79 San Bruno Indictment, Count 2, at P 63.

80 San Bruno Indictment at P 28.

81 NPRM, 81 Fed. Reg. at 20,769; see also Proposed § 192.917(b), 81 Fed. Reg. at 20,840-41.

82 Proposed § 192.917(b)(1), 81 Fed. Reg. at 20,841.

83 Proposed § 192.917(b)(2), 81 Fed. Reg. at 20,841.

84 Proposed § 192.917(b)(2), 81 Fed. Reg. at 20,841.

among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.”<sup>85</sup>

Arguably, in light of the San Bruno Indictment, Section 192.917(b)'s wide-ranging list of potentially relevant data is so broad that compliance becomes impossible in practice. For example, gathering and integrating every example of “industry experience for incident, leak and failure history” is likely to be impossible, and effort to comply with this requirement would require substantial time and resources.

### **Risk Assessment**

Although the current regulations require operators to perform risk analyses of each covered segment and use these analyses in making integrity management decisions, the regulations do not impose specific requirements defining the scope and nature of such risk analyses.<sup>86</sup> Most pipeline operators use a “relative index-model approach” to perform their risk assessments. However, “there is a wide range in scope and quality of the resulting analyses,” and it is “not clear that all of the observed risk analyses can support robust decision-making and management of the pipeline risk.”<sup>87</sup> In PHMSA's view, the risk models and risk assessments used by pipeline operators “should have substantially improved since the initial framework programs established nearly 10 years ago.”<sup>88</sup>

To clarify “the characteristics of a mature risk assessment program,” the NPRM proposes to amend Section 192.917(c). For each covered segment, the risk assessment must analyze identified threats and the “potential consequences of an incident.” The risk assessment must include evaluation of the effects of “interacting threats,” including “the potential for interactions of threats and anomalous conditions not previously evaluated.”<sup>89</sup> PHMSA also proposes to amend the regulation

to state that the risk assessment must: (i) analyze how a potential failure could affect HCAs, including the consequences of the entire worst-case incident scenario from initial failure to incident termination; (ii) analyze the likelihood of failure due to each individual threat or risk factor, and each unique combination of risk factors that interact or simultaneously contribute to risk at a common location; (iii) lead to a better understanding of the nature of the threat, the failure mechanisms, the effectiveness of currently deployed risk mitigation activities, and how to prevent, mitigate, or reduce those risks; (iv) account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and (v) evaluate the potential risk reduction associated with candidate risk reduction activities such as preventive and mitigative measures and reduced anomaly remediation and assessment intervals.<sup>90</sup>

In addition, the operator must validate its risk model “in light of incident, leak, and failure history and other historical information.”<sup>91</sup> This validation must: (i) ensure the risk assessment methods produce a “risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents as determined by root cause analysis or other equivalent means”; and (ii) include “sensitivity analysis” of the factors used “to characterize both the probability of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity.”<sup>92</sup>

### **Actions to Address Particular Threats**

Section 192.917(e) currently defines specific actions an operator must undertake when it identifies the following threats to pipeline integrity: third-party damage, cyclic fatigue, manufacturing and construction defects, the presence of electric resistance welded (“ERW”) pipe, and corrosion. With respect to the threats posed by cyclic fatigue and the presence of ERW pipe, PHMSA proposes to add the requirement that, for a pipe segment with

---

85 Proposed § 192.917(b)(4), 81 Fed. Reg. at 20,841.

86 49 C.F.R. §§ 192.907(a), 192.911(c).

87 NPRM, 81 Fed. Reg. at 20,762.

88 NPRM, 81 Fed. Reg. at 20,763.

89 Proposed § 192.917(c), 81 Fed. Reg. at 20,841-42.

90 Proposed § 192.917(c), 81 Fed. Reg. at 20,841-42.

91 Proposed § 192.917(c), 81 Fed. Reg. at 20,841.

92 NPRM, 81 Fed. Reg. at 20,766 (discussing Proposed § 192.917(c)).

cracks, the operator must conduct “fracture mechanics modeling” for failure stress pressures and cyclic fatigue crack growth in accordance with new Section 192.624(d).<sup>93</sup>

PHMSA also proposes to revise Section 192.917(e)(3), which addresses manufacturing and construction defects. Section 192.917(e)(3) currently states that an operator “may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area.” The regulation also states that “an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment” if certain changes occur in the covered segment, including if there are “operating pressure increases above the maximum operating pressure experienced during the preceding five years[.]”<sup>94</sup> PHMSA proposes to remove all reference to the five-year maximum operating pressure. Instead, under the NPRM, an operator may consider manufacturing and construction-related defects to be “stable defects” only if “the covered segment has been subjected to” a Subpart J pressure test of at least 1.25 times MAOP and the segment has not experienced “an in-service incident attributed to a manufacturing or construction defect since the date of the pressure test.

### New Assessment Methods

Currently, Section 192.921 requires a pipeline operator to assess a covered segment using one of four methods: (i) in-line inspection; (ii) a Subpart J pressure test; (iii) direct assessment; or (iv) “other technology.”<sup>95</sup> PHMSA proposes to add three new methods, for a total of seven assessment methods.<sup>96</sup>

First, PHMSA would add the “spike” pressure test performed in accordance with Section 192.506, “which is particularly well suited to address stress corrosion cracking.”<sup>97</sup> This spike pressure test is discussed in Section II.B of this White Paper.

Second, PHMSA proposes to add excavation and in situ direct examination as an allowed assessment method, “which is well suited to address crossovers and other short, easily accessible segments that are impractical to assess by remote technology.”<sup>98</sup> As revised, Section 192.921 (which addresses how a baseline assessment is conducted) lists as an assessment method the “[e]xcavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI),”<sup>99</sup> Section 192.937, which addresses the continual process of evaluation and assessment to maintain a pipeline’s integrity, would be amended to include the same language but also would state that, in identifying and characterizing anomalies, an operator “must consider uncertainties in in situ direct examination results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, and usage unity chart plots or equivalent for determining uncertainties and verifying performance on the type defects being evaluated)[.]”<sup>100</sup>

Third, PHMSA proposes to authorize the use of guided wave ultrasonic testing, or GWUT, “which is particularly appropriate in cases where short segments, such as roads or railroad crossings, are difficult to assess.”<sup>101</sup> GWUT has been treated as an “other technology” assessment method, for which an advance

---

93 Proposed § 192.917(e)(2), 81 Fed. Reg. at 20,842 (addressing cyclic fatigue) and (e)(4), 81 Fed. Reg. at 20,842 (addressing ERW pipe).

94 49 C.F.R. § 192.917(e)(3).

95 49 C.F.R. § 192.921.

96 See Proposed § 192.921(a), 81 Fed. Reg. at 20,842-43. With clarifications added by the NPRM, the use of “other technology” requires that an operator demonstrate, for each threat to which the pipeline is susceptible, that the method can provide an understanding of the pipeline’s condition that is equivalent to the other listed assessment methods. This requires that the operator notify PHMSA at least 180 days before conducting the assessment and receive a “no objection letter” from PHMSA. Proposed § 192.921(a)(7), 81 Fed. Reg. at 20,843.

97 NPRM, 81 Fed. Reg. at 20,734.

98 NPRM, 81 Fed. Reg. at 20,734.

99 Proposed § 192.921(a)(4), 81 Fed. Reg. at 20,843.

100 Proposed § 192.937(c)(4), 81 Fed. Reg. at 20,848.

101 NPRM, 81 Fed. Reg. at 20,734.

notification to PHMSA was required.<sup>102</sup> According to PHMSA, operators have “effectively used” guidelines developed by PHMSA in 2007 “to assess the integrity of short segments of pipe.”<sup>103</sup> PHMSA proposes to incorporate these guidelines into a new Appendix F to Part 192.<sup>104</sup> Thus, an operator would be permitted to use the GWUT method without providing PHMSA an “other technology” notification.<sup>105</sup>

### **New Requirements for Selecting and Using Assessment Methods**

With regard to in-line inspections, PHMSA proposes to require operators to comply with “the requirements and recommendations of” three industry standards: (i) API STD 1163, In-line Inspection Systems Qualification Standard; (ii) ANSI/ASNT ILI-PQ-2005, In-line Inspection Personnel Qualification and Certification; and (iii) NACE SP0102-2010, In-line Inspection of Pipelines. This requirement is implemented by “incorporation by reference” of these standards into Section 192.493.<sup>106</sup> In addition, when using the in-line inspection method, a pipeline operator must “explicitly consider uncertainties” in the way the in-line inspection “identifies and characterizes anomalies.”<sup>107</sup> PHMSA also proposes to add a new Section 192.750, which would require safety features on launchers and receivers associated with in-line inspection tools, scrapers, and spheres.<sup>108</sup>

The direct assessment method would be an option only if a line is not capable of inspection by in-line inspection methods.<sup>109</sup> Direct assessment “samples” locations along a pipeline

segment, whereas pressure testing and in-line inspection assess an entire segment. For this reason, pressure testing and in-line inspection “provide a higher level of assurance (though still not 100 percent) that no injurious pipeline defects remain in the pipe after an assessment is completed and anomalies repaired.”<sup>110</sup>

PHMSA also proposes to incorporate an industry standard, NACE SP0206-2006, to govern the use of internal corrosion direct assessments and another industry standard, NACE SP0204-2008, to govern the use of stress corrosion cracking direct assessment.<sup>111</sup> The changes to Section 192.927 impose a series of related requirements, including the requirement that, when performing an indirect inspection, operators must “use pipeline specific data, exclusively. The use of assumed pipeline or operational data is prohibited.”<sup>112</sup>

In developing these new requirements applicable to in-line inspections and direct assessments, PHMSA has chosen not to state some of the new requirements in the text of the regulations. Instead, PHMSA has chosen to incorporate by reference the requirements of various industry standards into the regulations. In fact, the NPRM proposes to incorporate nine new standards or reports by reference into Part 192.<sup>113</sup>

Section 24 of the 2011 Pipeline Safety Act, as amended, states that, beginning on January 3, 2015, the Secretary of DOT “may not issue a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless

---

102 NPRM, 81 Fed. Reg. at 20,734.

103 NPRM, 81 Fed. Reg. at 20,817.

104 Proposed § 192.921(a)(5), 81 Fed. Reg. at 20,843; see also Proposed Appendix F to Part 192, 81 Fed. Reg. at 20,855-56.

105 NPRM, 81 Fed. Reg. at 20,734.

106 NPRM, 81 Fed. Reg. at 20,773 (discussing Proposed § 192.921(a)(1)).

107 Proposed § 192.921(a)(1), 81 Fed. Reg. at 20,843. The uncertainties that must be considered include, “but [are] not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance.”

108 Proposed § 192.750, 81 Fed. Reg. at 20,840; NPRM, 81 Fed. Reg. at 20,815.

109 NPRM, 81 Fed. Reg. at 20,770; Proposed § 192.921(a)(6), 81 Fed. Reg. at 20,843.

110 NPRM, 81 Fed. Reg. at 20,770.

111 NPRM, 81 Fed. Reg. at 20,773-74.

112 Proposed § 192.927(b), 81 Fed. Reg. at 20,843.

113 Proposed § 192.7, 81 Fed. Reg. at 20,827.



the documents or portions thereof are made available to the public, free of charge.”<sup>114</sup> In the NPRM, PHMSA states that it has requested, from each relevant standards development organization, “a hyperlink to a free copy of each standard that has been proposed for incorporation by reference. Access to these standards will be granted until the end of the comment period for this proposed rulemaking.”<sup>115</sup> It is not clear that the steps described in the NPRM (such as making the newly referenced industry standards available only during the rulemaking comment period) satisfy 49 U.S.C. § 60102(p), as amended.

### New Preventive and Mitigative Measures

Section 192.935 defines the steps a pipeline operator must take, based on the results of its risk assessment, to prevent the failure of a covered segment and to mitigate the consequences of an incident on the covered segment. Currently, the regulation includes a nonexclusive list of preventive and mitigative measures a pipeline operator should consider. In its ANPRM, PHMSA expressed concern that operators may be considering only those methods listed as examples in the regulation, rather than employing “appropriate additional measures as intended.”<sup>116</sup>

PHMSA proposes to expand Section 192.935’s list of preventive and mitigative measures that an operator must consider, which includes, but (once again) is not limited to: installing automatic shut-off valves or remote control valves; installing computerized monitoring and leak detection systems; replacing pipe segments with pipe of heavier wall thickness; providing additional training to personnel on response procedures; conducting drills with local emergency responders; and implementing additional inspection and maintenance programs, among others.<sup>117</sup> According to

PHMSA, these changes “do not alter the fundamental requirement” related to preventive and mitigative measures but instead provide “additional guidance and clarify PHMSA’s expectations.”<sup>118</sup>

PHMSA proposes to impose “enhanced” preventive and mitigative measures addressing internal corrosion control and external corrosion control.<sup>119</sup> To address internal corrosion, the proposed rule states that, as an operator “gains information about internal corrosion,” the operator “must enhance” its internal corrosion management program.<sup>120</sup> The operator must, “at a minimum,” (i) monitor for, and mitigate the presence of, deleterious gas stream constituents; (ii) use filter separators or separators and continuous gas quality monitoring equipment at points where gas with potentially deleterious contaminants enters the pipeline; (iii) use gas quality monitoring equipment at least once per quarter; (iv) use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion; (v) use inhibitors when corrosive gas or corrosive liquids are present; (vi) address potentially corrosive gas stream constituents as specified in Section 192.478(a) where the volumes exceed specified amounts over a 24-hour interval; and (vii) review the program at least semiannually based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.<sup>121</sup>

To address external corrosion, the proposed rule states that, as an operator “gains information about external corrosion,” the operator “must enhance” its external corrosion management program.<sup>122</sup> The operator must, “at a minimum,” (i) control electrical interference currents that can adversely affect cathodic protection; (ii) monitor and confirm the effectiveness

---

114 2011 Pipeline Safety Act, § 24, 125 Stat. at 1919, amending 49 U.S.C. § 60102 by adding a new subsection (p).

115 NPRM, 81 Fed. Reg. at 20,821. According to PHMSA, access to these documents can be found on the PHMSA Web site at the following URL: <http://www.phmsa.dot.gov/pipeline/regs> under “Standards Incorporated by Reference.”

116 NPRM, 81 Fed. Reg. at 20,750 (summarizing the ANPRM).

117 Proposed § 192.935(a), 81 Fed. Reg. at 20,846.

118 NPRM, 81 Fed. Reg. at 20,820.

119 NPRM, 81 Fed. Reg. at 20,754.

120 Proposed § 192.935(f), 81 Fed. Reg. at 20,846.

121 Proposed § 192.935(f), 81 Fed. Reg. at 20,846.

122 Proposed § 192.935(g), 81 Fed. Reg. at 20,846-47.

of external corrosion control through electrical interference surveys and indirect assessments, including cathodic protection surveys and coating surveys; (iii) take actions needed to mitigate conditions that are unfavorable to effective cathodic protection; and (iv) integrate the results of these surveys with integrity assessment and other integrity-related data.<sup>123</sup>

In addition to the requirements related to electrical interference currents that apply to all pipeline segments, Proposed Section 192.935(g)(1) would require an operator to analyze the results of the electrical interference survey to identify locations “where interference currents are greater than or equal to 20 Amps per meter squared” for covered segments. Any location with electrical interference currents greater than 50 Amps per meter squared “must be remediated,” and, if any AC interference between 20 and 50 Amps per meter squared “is not remediated, the operator must provide and document an engineering justification.”<sup>124</sup>

Section 29 of the 2011 Pipeline Safety Act requires operators to consider the seismicity of the area when evaluating potential threats to each pipeline segment.<sup>125</sup> PHMSA proposes to codify this statutory requirement by adding requirements in the rule to “include seismicity of the area in evaluating preventive and mitigative measures with respect to the threat of outside force damage.”<sup>126</sup>

## **NEW REQUIREMENTS APPLICABLE TO ALL PIPELINES, NOT JUST PIPELINES LOCATED IN HCAs AND MCAs**

### **Repair Criteria**

Currently, Section 192.713 of PHMSA’s regulations states that each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40

percent of SMYS must be replaced or repaired, but it does not specify the deadline for such repair.<sup>127</sup> For segments located outside of HCAs, PHMSA proposes to define three sets of repair conditions, each of which is subject to a different time frame for remediating the defect: immediate repair conditions, two-year repair conditions, and monitored conditions. According to PHMSA, these changes will “provide greater assurance that injurious anomalies and defects are repaired before the defect can grow to a size that leads to a leak or rupture.”<sup>128</sup>

As amended, Section 192.713 would require immediate repair of: (i) an anomaly where the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times MAOP; (ii) a dent that has any indication of metal loss, cracking, or a stress riser; (iii) metal loss greater than 80 percent of nominal wall regardless of dimensions; (iv) an indication of metal loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high-frequency electric resistance welding or by electric flash welding; (v) any indication of significant stress corrosion cracking; (vi) any indication of significant selective seam weld corrosion; or (vii) an “indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.”<sup>129</sup> Until an immediate repair condition is repaired, the operator “must reduce the operating pressure of the affected pipeline” to the lower of: (i) 80 percent of the pressure at the time of discovery of the condition; or (ii) a level that “restores the safety margin commensurate with the design factor” for the affected pipeline’s Class location.<sup>130</sup>

For non-HCA segments, PHMSA defines seven conditions that must be remediated within two years: (i) two types of dents with defined characteristics; (ii) an anomaly where the remaining strength of the pipe shows a predicted failure pressure less than or equal to MAOP times a factor that increases

---

123 NPRM, 81 Fed. Reg. at 20,754, and Proposed § 192.935(g), 81 Fed. Reg. at 20,846-47.

124 Proposed § 192.935(g)(1)(i), 81 Fed. Reg. at 20,847; NPRM, 81 Fed. Reg. at 20,784.

125 2011 Pipeline Safety Act, § 29, 125 Stat. at 1921, codified at 49 U.S.C. § 60109 note.

126 NPRM, 81 Fed. Reg. at 20,820 (discussing Proposed § 192.935(b)(2)).

127 See 49 C.F.R. § 192.713.

128 NPRM, 81 Fed. Reg. at 20,754.

129 Proposed § 192.713(d)(1), 81 Fed. Reg. at 20,839.

130 Proposed § 192.713(d)(2), 81 Fed. Reg. at 20,839-40. This safety margin must be established by applying two industry standards that are incorporated by reference into the regulation. See Proposed § 192.713(d)(2)(i), 81 Fed. Reg. at 20,840.

based on Class location (1.25 in Class 1, 1.39 in Class 2, 1.67 in Class 3, and 2.00 in Class 4); (iii) an area of general corrosion with a predicted metal loss greater than 50 percent of nominal wall; (iv) predicted metal loss greater than 50 percent of nominal wall, located at a pipeline crossing or located in an area with widespread circumferential corrosion or an area that could affect a girth weld; (v) a gouge or groove greater than 12.5 percent of nominal wall; and (vi) any indication of a crack or crack-like defect other than an immediate repair condition.<sup>131</sup> For covered segments within an HCA, these same conditions must be remediated within one year.<sup>132</sup> Finally, Section 192.713, as amended, would require pipeline operators to monitor certain types of defects rather than schedule them for remediation.<sup>133</sup>

### Inspection of Pipelines Following Severe Events

PHMSA proposes to amend Section 192.613 to require pipeline operators to inspect “all potentially affected onshore transmission pipeline facilities” following an “an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event that has the likelihood of damage to infrastructure[.]”<sup>134</sup> In selecting an inspection method, the operator would be required to consider “the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline[.]”<sup>135</sup> The operator must commence the inspection within 72 hours after “the cessation of the event,” which is defined as the point in time when the affected area “can be safely accessed by personnel and equipment, including the availability of personnel and equipment[.]”<sup>136</sup>

Based on the information obtained through this inspection, the operator must take appropriate remedial action.<sup>137</sup> Such remedial action includes, but is not limited to: (i) reducing the operating pressure or shutting down the pipeline; (ii) modifying, repairing, or replacing any damaged pipeline facilities; (iii) preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way; (iv) performing additional patrols, surveys, tests, or inspections; (v) implementing emergency response activities with federal, state, or local personnel; or (vi) notifying affected communities of the steps that can be taken to ensure public safety.<sup>138</sup>

### Reporting MAOP Exceedances

Section 23 of the 2011 Pipeline Safety Act states that, if there is an exceedance of MAOP on a gas transmission pipeline “that exceeds the build-up allowed for operation of pressure-limiting or control devices,” then the owner or operator of the pipeline “shall report the exceedance[.]”<sup>139</sup> In the NPRM, PHMSA proposes to amend Section 191.23 to implement this requirement.<sup>140</sup>

### Management of Change Procedures

A change to the physical characteristics of a pipeline (such as changes to pipeline equipment, computer equipment, or software used to monitor and control the pipeline) as well as a change to the practices and procedures used to construct, operate, and maintain those physical systems can pose a risk to pipeline safety.<sup>141</sup> PHMSA proposes to revise Section 192.13 to state that each operator of an onshore gas transmission pipeline must “develop and follow a management of change

---

131 Proposed § 192.713(d)(3), 81 Fed. Reg. at 20,840.

132 Proposed § 192.933(d)(2), 81 Fed. Reg. at 20,846.

133 Proposed § 192.713(d)(4), 81 Fed. Reg. at 20,840.

134 Proposed § 192.613(c), 81 Fed. Reg. at 20,832-33.

135 Proposed § 192.613(c)(1), 81 Fed. Reg. at 20,832.

136 Proposed § 192.613(c)(2), 81 Fed. Reg. at 20,832.

137 Proposed § 192.613(c)(3), 81 Fed. Reg. at 20,832-33.

138 Proposed § 192.613(c)(3), 81 Fed. Reg. at 20,832-33.

139 2011 Pipeline Safety Act, § 23, 125 Stat. at 1918, codified at 49 U.S.C. § 60139(b)(2).

140 Proposed § 191.23(a)(9), 81 Fed. Reg. at 20,824.

141 NPRM, 81 Fed. Reg. at 20,795.

process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or process, whether permanent or temporary.”<sup>142</sup> For any such change, this management of change process must address: (i) the reason for the change; (ii) the authority for approving the change; (iii) an analysis of the implications of the change; (iv) the acquisition of required work permits; (v) documentation; (vi) communication of the change to affected parties; (vii) time limitations; and (viii) qualification of staff.<sup>143</sup>

### Corrosion Control

PHMSA proposes to amend its regulations governing corrosion control to: (i) require post-construction electrical surveys for coating damage; (ii) enhance requirements for electrical surveys (i.e., close interval surveys); (iii) require interference current surveys; (iv) add more explicit requirements for internal corrosion control; and (v) revise Part 192, Appendix D to better align with the criteria for cathodic protection in NACE SP0169.<sup>144</sup>

Currently, pipeline operators must employ cathodic protection to protect pipelines from external corrosion. Cathodic protection is a “means of protecting a buried pipe against corrosion. A current is directed onto the pipe by sacrificial anodes [sic] (metal ribbons) placed in the ground, parallel to and connected to the pipe. Pipe will not corrode if sufficient current flows onto the pipe.”<sup>145</sup> An electric current survey can be used to evaluate whether the electric current along the pipeline is adequate for purposes of the cathodic protection program.

Under PHMSA’s current rules, all buried or submerged pipelines installed after July 31, 1971, must have an external protective coating that meets certain requirements.<sup>146</sup> According to PHMSA, experience has shown that a pipeline’s external coating can be damaged by construction activities.<sup>147</sup> PHMSA therefore proposes to revise Section 192.461 to require operators to “promptly, but no later than three months after backfill of an onshore transmission pipeline ditch” following a repair or replacement that results in 1,000 feet or more of backfill length along the pipeline, “conduct surveys to assess any coating damage to ensure integrity of the coating[.]”<sup>148</sup> The survey must test for direct current voltage gradient or alternating current voltage gradient. If the survey identifies coating damage “classified as moderate or severe,” the operator must remediate the damage within six months of the survey.<sup>149</sup>

PHMSA also proposes to amend Section 192.465 to state that, for onshore transmission lines, if any annual test station reading (pipe-to-soil potential measurement) “indicates cathodic protection levels below the required levels” specified in Part 192, Appendix D, then the operator “must determine the extent of the area with inadequate cathodic protection.”<sup>150</sup> This requires that the operator conduct “close interval surveys” in both directions from the test station using a minimum of approximately five foot intervals. These close interval surveys “must be completed with the protective current interrupted unless it is impractical to do so for technical or safety reasons.”<sup>151</sup> As with any other cathodic protection deficiency identified through the monitoring required by Section 192.465, “areas with insufficient

---

142 NPRM, 81 Fed. Reg. at 20,828.

143 NPRM, 81 Fed. Reg. at 20,828.

144 NPRM, 81 Fed. Reg. at 20,782.

145 8-C Williams & Meyers, Oil and Gas Law (LexisNexis Matthew Bender 2015) (quoting General Accounting Office, [Trans-Alaska Pipeline](#) 22 n.1 (GAO/RCED-91-89, July 19, 1991).

146 See 49 C.F.R. §§ 192.455(a), 192.461.

147 NPRM, 81 Fed. Reg. at 20,783 (discussing the ANPRM).

148 Proposed § 192.461(f), 81 Fed. Reg. at 20,829.

149 Coating damage is classified as “moderate or severe” if there is a “voltage drop greater than 35%” for direct current voltage gradient “or 50 dB-v” for alternating current voltage gradient in accordance with Section 4 of NACE SP0502, which is incorporated by reference into the regulation. Proposed § 192.461(f), 81 Fed. Reg. at 20,829.

150 Proposed § 192.465(f), 81 Fed. Reg. at 20,829.

151 Proposed § 192.465(f), 81 Fed. Reg. at 20,829.

cathodic protection levels or areas where protective current is found to be leaving the pipeline” must be remediated “promptly, but no later than the next monitoring interval in § 192.465 or within one year, whichever is less.”<sup>152</sup>

An independent source of electric current located near a pipeline can interfere with the electric current being supplied for cathodic protection purposes. Under PHMSA’s proposal, operators would be required to conduct “interference surveys” to detect “the presence and level of any electrical stray current,” undertaken on a “periodic basis including, when there are current flow increases over pipeline segment grounding design,” from sources such as co-located pipelines, structures, or high-voltage alternating current power lines, including changes in those lines, additional lines, new pipelines, or other structures.<sup>153</sup> In addition, the operator’s interference current program must analyze the results of the survey “to determine the cause of the interference and whether the level could impact the effectiveness of cathodic protection.”<sup>154</sup> The operator must take remedial actions “to protect the pipeline segment from detrimental interference currents promptly but no later than six months after completion of the survey.”<sup>155</sup>

With respect to internal corrosion control, PHMSA proposes to add new Section 192.478 to require each operator to develop and implement “a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects.”<sup>156</sup> An operator must evaluate “the partial pressure of each corrosive constituent by itself or in combination” to evaluate the corrosive constituents’

effect on “the internal corrosion of the pipe and implement mitigation measures.”<sup>157</sup> The monitoring and mitigation program must include: (i) at points where gas with potentially corrosive contaminants enters the pipeline, the use of gas-quality monitoring equipment to determine the gas stream constituents; (ii) “product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents”; and (iii) an evaluation twice each calendar year at intervals not to exceed 7-½ months “of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.”<sup>158</sup> If the pipeline is transporting corrosive gas, then the operator must use and check at least twice each calendar year at intervals not exceeding 7-½ months “coupons or other suitable means” to determine the effectiveness of the steps taken to minimize internal corrosion.<sup>159</sup>

## EXPANDING THE REGULATION OF GAS GATHERING LINES

Section 21 of the Pipeline Safety Act of 2011 directed PHMSA to conduct a study of gathering lines to assess the sufficiency of the existing regulatory regime, the economic impact and feasibility of applying existing regulations to gathering lines, and the need to modify or revoke existing gathering line exemptions.<sup>160</sup> In the NPRM, PHMSA notes that the study has been completed and placed in the docket.<sup>161</sup>

---

152 Proposed § 192.465(d), (f), 81 Fed. Reg. at 20,829.

153 Proposed § 192.473(c)(1), 81 Fed. Reg. at 20,829.

154 Proposed § 192.473(c)(2), 81 Fed. Reg. at 20,829.

155 Proposed § 192.473(c)(3), 81 Fed. Reg. at 20,829-30.

156 Proposed § 192.478(a), 81 Fed. Reg. at 20,830.

157 Proposed § 192.478(a), 81 Fed. Reg. at 20,830.

158 Proposed § 192.478(b), 81 Fed. Reg. at 20,830.

159 Proposed § 192.478(c), 81 Fed. Reg. at 20,830.

160 2011 Pipeline Safety Act, § 21, 125 Stat. at 1917.

161 NPRM, 81 Fed. Reg. at 20,80-02; see also [Letter from Anthony Foxx](#), Secretary of Transportation, to John Thune, Chairman, Committee on Commerce, Science and Transportation, U.S. Senate regarding Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Gathering Lines (May 8, 2015).

Currently, a “gathering line” is defined as a pipeline “that transports gas from a current production facility to a transmission line or main.”<sup>162</sup> An “onshore gathering line” is defined primarily by applying an industry standard, American Petroleum Institute Recommended Practice 80, “Guidelines for the Definition of Onshore Gas Gathering Lines,” which is incorporated by reference into Section 192.8(a).<sup>163</sup> API RP-80 uses the location of various types of equipment to distinguish between production and gathering lines.

PHMSA’s regulations then distinguish between two categories of “regulated” gathering lines:

- Type A, which is an onshore gathering line (or segment of an onshore gathering line) comprising metallic pipe with an MAOP of 20 percent or more of SMYS, as well as non-metallic lines with an MAOP of more than 125 psig, if the pipe is located in a Class 2, 3, or 4 location; and
- Type B, which is an onshore gathering line (or segment of an onshore gathering line) comprising metallic pipe with an MAOP of less than 20 percent of SMYS, as well as non-metallic lines with an MAOP of 125 psig or less, if the pipe is located in Class 2, 3, or 4 location.<sup>164</sup>

Under the current regulations, an onshore gathering line located in a Class 1 location is not a “regulated” gathering line, and therefore it is not subject to the requirements of Part 192. Type A gathering lines are subject to nearly all of the requirements of Part 192 for transmission lines, except the

requirements in Section 192.150 and in Subpart O. Type B gathering lines are subject only to six requirements specifically listed in Section 192.9(d).<sup>165</sup>

According to PHMSA, its enforcement of requirements applicable to gathering “has been hampered by the conflicting and ambiguous language of API RP-80, which is complex and can produce multiple classifications for the same pipeline system.”<sup>166</sup> Because of “the ambiguous language and terminology” in API RP-80, “experience has shown that facilities are being classified as production much further downstream than was ever intended.”<sup>167</sup> In addition, the concept of “incidental gathering” as used in API RP-80 “has not been applied as intended.”<sup>168</sup>

In the NPRM, PHMSA proposes to modify the definition of “gathering line (onshore)” to mean “a pipeline, or a connected series of pipelines, and equipment used to collect gas from the endpoint of a production facility/operation and transport it to the furthestmost point downstream of” the four defined “endpoints.”<sup>169</sup> An “onshore production facility” or “onshore production operation” is defined by the NPRM to mean “wellbores, equipment, piping, and associated appurtenances confined to the physical acts of extraction or recovery of gas from the earth and the initial preparation for transportation.”<sup>170</sup> Moreover, production facilities “terminate at the furthestmost downstream point where: Measurement for the purposes of calculating minerals severance occurs; or there is commingling of the flow stream from two or more wells.”<sup>171</sup> In conjunction with clarified definitions, PHMSA proposes to require operators to determine

---

<sup>162</sup> 49 C.F.R. § 192.3.

<sup>163</sup> 49 C.F.R. § 192.8(a).

<sup>164</sup> 49 C.F.R. § 192.8(b).

<sup>165</sup> 49 C.F.R. § 192.9 requires on operator to: (i) conduct initial testing according to requirements applicable to transmission lines if a line is new, replaced, relocated or otherwise changed; (ii) control corrosion according to the requirements of subpart I; (iii) carry out a damage prevention program under § 192.614; (iv) establish a public education program under § 192.616; (v) establish the MAOP of the line under § 192.619; and (vi) install and maintain line markers according to the requirements for transmission lines in § 192.707.

<sup>166</sup> For example, “separators are defined for both production and gathering almost verbatim.” NPRM, 81 Fed. Reg. at 20,803.

<sup>167</sup> NPRM, 81 Fed. Reg. at 20,803.

<sup>168</sup> NPRM, 81 Fed. Reg. at 20,803.

<sup>169</sup> Proposed § 192.3, 81 Fed. Reg. at 20,825. The definition also states that “preparation for transportation does not necessarily mean the gas will meet ‘pipeline quality’ specifications as may be commonly understood or contained in many contractual agreements,” and that “piping” as used in this definition “may include individual well flow lines, equipment piping, and transfer lines between production operation equipment components.”

<sup>170</sup> Proposed § 192.3, 81 Fed. Reg. at 20,826.

<sup>171</sup> Proposed § 192.3, 81 Fed. Reg. at 20,826.

and maintain records documenting beginning and end points of each gathering line.<sup>172</sup> These records are to be complete within six months of the effective date of the rule or before the pipeline is placed in operation.<sup>173</sup>

To distinguish between the requirements applicable to different types of gathering lines, PHMSA proposes to divide Type A gathering lines into “Area 1” lines and “Area 2” lines. The Type A, Area 1 designation would apply to lines currently regulated as Type A gathering lines, and these lines would be required to comply with most of the requirements of Part 192 for transmission lines.<sup>174</sup> Area 2 lines are those Type A lines located in a Class 1 location with a nominal diameter of eight inches or greater. These Type A, Area 2 lines, which currently are a subset of “unregulated” gathering lines, would be subject to the six requirements that apply to Type B lines under Section 192.9(d), plus the requirement to conduct leakage surveys in accordance with Section 192.706.<sup>175</sup> Operators would be required to comply with the new gathering requirements within two years after the effective date of the final rule.<sup>176</sup> After the rule goes into effect, if a line’s status changes due to a class location change or due to an increase in dwelling density, an operator would need to comply with the Type A, Area 2 requirement within one year of the change and to comply with the Type B requirements within two years of the change.<sup>177</sup>

Currently, “unregulated” onshore gathering lines are not subject to the reporting requirements of Part 191, which requires operators to submit annual, incident, and safety-related condition reports to PHMSA.<sup>178</sup> PHMSA proposes to “delete the

exemption for reporting requirements for operators of unregulated onshore gas gathering lines.”<sup>179</sup> Thus, all classes of pressurized onshore gathering lines will be subject to reporting requirements under Section 191. PHMSA believes that the data requirements would allow for further evaluation of the lines, including whether the lines warrant additional regulation.<sup>180</sup>

## TOPICS DEFERRED TO THE FUTURE

With respect to the potential requirement that operators install automatic or remote-controlled shutoff valves, PHMSA recognized that: (i) the NTSB, through recommendation P-11-11 included in its report on the San Bruno incident, recommended that PHMSA promulgate regulations to explicitly require that automatic shutoff valves or remote control valves be installed in HCAs and in Class 3 and 4 locations and spaced at intervals considering the population factors listed in the regulations; and (ii) Congress, through Section 4 of the 2011 Pipeline Safety Act, required issuance of regulations on the use of automatic or remote-controlled shutoff valves, or equivalent technology, if appropriate, and where economically, technically, and operationally feasible.<sup>181</sup>

Likewise, with respect to potential new regulations addressing underground storage facilities, the NPRM states that “underground storage facilities including surface and subsurface well casing, tubing, and valves are not currently regulated under Part 192.” PHMSA notes several recent developments related to the safety of underground storage facilities, including an incident at Southern California Gas Company’s Aliso Canyon

---

172 Proposed § 192.8(a), 81 Fed. Reg. at 20,827.

173 Proposed § 192.8(b), 81 Fed. Reg. at 20,827.

174 Proposed § 192.9(c); 81 Fed. Reg. 20,828. Types A, Area 1 gathering lines would be required to comply with all of the requirements in Part 192, with the exception of the requirements in Sections 192.13, 192.150, 192.319, 192.461(f), 192.465(f), 192.473(c), 192.478, 192.710, 192.713, and in Subpart O.

175 Proposed § 192.9, 81 Fed. Reg. at 20,828; NPRM, 81 Fed. Reg. at 20,723.

176 Proposed § 192.9(e); 81 Fed. Reg. 20,828.

177 Proposed § 192.9(f); 81 Fed. Reg. 20,828.

178 49 C.F.R. § 191.1.

179 NPRM, 81 Fed. Reg. at 20,803. See Proposed § 191.1, 81 Fed. Reg. at 20,824.

180 NPRM, 81 Fed. Reg. at 20,803.

181 NPRM, 81 Fed. Reg. at 20,734 and 20,780.

natural gas storage facility and PHMSA's issuance of an advisory bulletin "to remind" all owners and operators of underground storage facilities used for the storage of natural gas to "consider the overall integrity of the facilities to ensure the safety of the public and operating personnel and to protect the environment."<sup>182</sup>

The NPRM explains that PHMSA intends to address these and other subjects through future rulemaking initiatives, including:

- Whether (and to what extent) pipeline operators should be required to install valves that shut off automatically in response to an incident or can be shut off remotely.<sup>183</sup>
- Whether to issue rules focusing on improving the safety of underground natural gas storage facilities.<sup>184</sup>
- Whether pipeline operators should be required to upgrade all gas pipelines so that they can accommodate in-line inspection tools.<sup>185</sup>
- Whether to apply Integrity Management or risk management principles to regulated gathering lines.<sup>186</sup>
- Applying enhanced internal corrosion requirements to regulated gathering lines.<sup>187</sup>
- Imposing additional preventive and mitigative measures for non-HCA pipeline segments.<sup>188</sup>
- New minimum safety standards for managing the threat of Stress Corrosion Cracking.<sup>189</sup>
- Imposing new Quality Management System requirements and/or developing "performance measures."<sup>190</sup>

## LAWYER CONTACTS

For further information, please contact your principal Firm representative or one of the lawyers listed below. General email messages may be sent using our "Contact Us" form, which can be found at [www.jonesday.com/contactus/](http://www.jonesday.com/contactus/).

### **Kenneth B. Driver**

Washington  
+1.202.879.7629  
[kbdriver@jonesday.com](mailto:kbdriver@jonesday.com)

### **David A. Kutik**

Cleveland  
+1.216.586.7186  
[dakutik@jonesday.com](mailto:dakutik@jonesday.com)

### **Charles C. Read**

Los Angeles / Washington  
+1.213.243.2818 / +1.202.879.5568  
[ccread@jonesday.com](mailto:ccread@jonesday.com)

### **Jennifer M. Hayes**

Pittsburgh  
+1.412.394.7992  
[jhayes@jonesday.com](mailto:jhayes@jonesday.com)

*Nicholas M. Faas, Brian L. Greenert, and Daniel P. Hido, associates in the Pittsburgh Office, and Daniel J. Bleiberg, an associate in the Washington Office, assisted in the preparation of this White Paper.*

---

<sup>182</sup> Pipeline Safety: Safe Operations of Underground Storage Facilities for Natural Gas, Advisory Bulletin (ADB-2016-02), 81 Fed. Reg. 6334 (Feb. 5, 2016).

<sup>183</sup> NPRM, 81 Fed. Reg. at 20,734, 20,780-81.

<sup>184</sup> NPRM, 81 Fed. Reg. at 20,734-35, 20,795.

<sup>185</sup> NPRM, 81 Fed. Reg. at 20,734, 20,772.

<sup>186</sup> NPRM, 81 Fed. Reg. at 20,735, 20,804.

<sup>187</sup> NPRM, 81 Fed. Reg. at 20,805-06.

<sup>188</sup> NPRM, 81 Fed. Reg. at 20,754.

<sup>189</sup> NPRM, 81 Fed. Reg. at 20,785, 20,788.

<sup>190</sup> NPRM, 81 Fed. Reg. at 20,763, 20,798.

Jones Day publications should not be construed as legal advice on any specific facts or circumstances. The contents are intended for general information purposes only and may not be quoted or referred to in any other publication or proceeding without the prior written consent of the Firm, to be given or withheld at our discretion. To request reprint permission for any of our publications, please use our "Contact Us" form, which can be found on our web site at [www.jonesday.com](http://www.jonesday.com). The mailing of this publication is not intended to create, and receipt of it does not constitute, an attorney-client relationship. The views set forth herein are the personal views of the authors and do not necessarily reflect those of the Firm.